Alberta
ENERGY

Petroleum Plaza – North Tower
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09-04

GAS ROYALTY CALCULATION INFORMATION BULLETIN April 2009

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PLEASE ENSURE YOUR PRODUCTION ACCOUNTANTS RECEIVE A COPY OF THIS DOCUMENT.

A. PRICING RATES AND TRANSPORTATION INFORMATION

For Pricing, Royalty Rates and Transportation Information for February 2009, refer to Attachments 1, 1A, 2, 2A, and 3. These attachments are also available in Excel format.

B. NOTICES

Annual Operating Cost Adjustments for 2003 through 2008 Production Years

Royalty Clients may have a charge type on their February 2009 invoice titled "Annual Operating Cost Adjustment". This adjustment represents the difference between the actual annual operating costs and the accumulated estimated monthly unit operating cost rate (UOCR) deductions, including any prior annual adjustments, for the 2003 through 2008 production years. Two reports are included with the invoice titled Annual Operating Cost Adjustment Details and Annual Operating Cost Adjustment Summary. Annual Operating Cost Adjustments are processed once a year in the February invoice issued in April. Each prior year's actual rates from this year's UOCR calculation process are published on the Royalty Related Information page on the department website. Please select **Unit Operating Cost Rates** to view the most recent actual rates for each year.

Effective with the 2009 production year, operating costs will be distributed to owners of each facility in a similar manner as capital costs and custom processing fees. This new method of distribution does not require an estimated or actual UOCR and there is no subsequent need to recapture operating costs from non-owners at the end of the year.

For additional information, please refer to the March 2004 Supplement Information Bulletin 04-03A as well as the Changes to Gas Cost Allowance link on the department website. If you require further information on these changes, please contact your respective Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin.

Royalty Liable Gas Used for Fuel (PURREC and PURDISP) and System Enhancement in PRA

When there is a sale of gas or transfer of ownership within the royalty network the gas volume is subject to royalty. Currently where the gas is sold and is used for fuel, it must be reported as a "PURREC" (Purchased Receipt) by the facility operator receiving it. This auto creates a PURDISP at the seller's facility.

For example: If a Gas Plant (GP) sells gas for fuel to a Battery (BT) each month, the reporting is:
1. The BT operator must report a PURREC.
2. This will auto populate a PURDISP at the GP.
3. The GP operator must then file a SAF/OAF for the PURDISP.

Please note that the seller of the gas that is used for fuel is not absolved from royalty liability and interest where the purchaser fails to report correctly. All parties should take steps to ensure that in

network sales or transfers of gas are correctly reported. Any amendments and recalculations that are required as a result of the review are communicated to the affected parties as soon as possible.

PROPOSED Change in reporting and system enhancement in PRA

To enhance the controls to prevent fuel gas volumes being incorrectly reported, the department, in consultation with PRA, will be implementing a change in the reporting responsibility within PRA such that the reporting will be reversed – i.e. the Seller will be required to report PURDISP which would then auto create PURREC at the Purchaser's facility. This shift in responsibility and reporting has been scheduled for June 2009. Further updates will follow in future Information Bulletins.

Well Event Measured Depth Determination Letter

The department has issued a "Well Event Measured Depth Determination Letter" under the Report Package DOE – Gas to facility operators via the PRA on April 2 and April 16, 2009. This letter shows the confirmed Measured Depth (MD) of each active well event that will be used to calculate the Depth Factor (DF) of the quantity component rate under the new royalty formula. A well event that is not listed on the letter and does not have a confirmed MD will receive a DF of 1. When the changes to the MD are confirmed by the department, a letter is issued to a facility operator who reports changes through the PRA to well event attributes affecting MD. All changes to the MD are applied on a go forward basis only, if a retroactive change is required, a written request must be submitted to the department. Facility operators are advised to submit well event attribute changes by the last day of the calendar month in order for timely determination of MD.

CSV File Format Updates due to Alberta Royalty Framework Transition Royalty Rates

Effective the May 2009 billing period invoice, issued in the calendar month of July 2009, the following change will be made as a result of implementing Transition Royalty Rates:

Add a formula column, to the below listed CSV files, that will indicate which formula is used in the calculation of Royalty Rates:

- CONDRR (Condensate Average Royalty Rate) specifications and samples are available in Excel format
- RGWERR (Raw Gas (RGA) Well Event Average Royalty Rate) specifications and samples are available in Excel format
- WEARR (Well Event Average Royalty Rate) specifications and samples are available in Excel format

Software providers and industry members who have requested this information, from the Business Systems Coordination team, have been notified of this change. As a precaution and to ensure that all software providers have been notified please forward this information as deemed necessary.

If you require further information on these changes, please contact Penny White at 780-422-9261.

C. MONTHLY INFORMATION

February 2009 Royalty Due May 31

- **Royalty clients are to remit the total amount payable shown on the May 2009 Statement of Account by May 31, 2009.** If the amount payable includes accrued current period interest, the interest has only been accrued to the statement issue date. Clients must also include the additional interest that has accrued from the statement issue date to the date of payment, using the per diem amount provided.

- **The May 2009 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your February 2009 invoice amount and any applicable current period interest charges. It also identifies refunds resulting from overpayments.**

- Current period interest will not be charged on current invoice charges for the production month of February 2009 if it is paid in full by May 31, 2009.
- Current period interest will accrue on any overdue charges commencing the first day after the due-date until it is paid in full.
- **Note: If the due date falls on a non-business day, the next business day will apply as the due date.**
- Cheques are payable to the Minister of Finance, Province of Alberta.

March 2009 VA4 Due May 15

The VA4 forms for the production month of March 2009 are due in the department offices by May 15, 2009.

Note: If the due date falls on a non-business day, the next business day will apply as the due date for VA4 forms.

Registry Deadline Submissions

The Registry deadline submissions for SAF, OAF, and Volumetrics are posted in the Petroleum Registry of Alberta website "Reporting Calendars" under Bulletin Board.

Changes to this calendar will be posted on the Registry website home page in "Broadcast Messages."

Interest Rate April 2009

Alberta Energy's interest rate for April 2009 is 3.50%.

January Provisional Assessment Charge

The summary of Provisional Assessment Charges for all production periods in the January 2009 billing period was:

First Time Provisional Assessment	Reversals of Provisional Assessments	Net Provisional Assessment
$4,373,127.90	($20,752,546.07)	($16,379,418.17)

January Penalty Charges

The penalty table below shows at the form level, the total penalty charges and reversals, for the January 2009 billing period:

FORM	Penalty Charges	Penalty Reversals	Net Penalty Charges for 2009/01
AC2	$55,100	($94,100)	($39,000)
AC4	$800	$0	$800
AC5	$3,400	$0	$3,400
GR2	$0	$0	$0
NGL1	$0	$0	$0
VA2	$0	$0	$0
VA3	$0	$0	$0
VA4	$400	$0	$400
Total	$59,700	($94,100)	($34,400)

Gas Royalty Calculation Support

Upon request, Gas Royalty Calculation staff will be available to meet with clients who need assistance with royalty reporting. Royalty clients requiring assistance are encouraged to contact your respective Gas Royalty Client Services portfolio representative, as identified in Section F of this bulletin, to arrange a meeting.

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

The BA Identifiers Report is a directory of Business Associate (BA) names, codes, status (e.g. struck, active, amalgamated, etc.), status effective dates, and effective August 2004, includes Working Interest Owner (WIO) role start/end dates.

This report is also published daily on the Petroleum Registry website at:

http://www.petroleumregistry.gov.ab.ca

The department reminds Business Associates to review their WIO role to ensure the start and end dates are reflected correctly. If the BA does not have an active WIO role, the operators cannot allocate volumes to the BA for the relevant production periods through the SAF/OAF allocations.

- If a BA has a WIO role, then that BA can receive SAF/OAF allocations from the WIO role start date forward.

- If a BA has a WIO role with an end date, then they can only receive SAF/OAF allocations from the WIO role start date until the end date. Any SAF/OAF allocations after the end date will be rejected.

- If a BA does not have a WIO role start date, then that BA cannot receive SAF/OAF allocations.

Please contact Client Registry at 780-422-1395 if you have any questions regarding the information supplied on this listing.

Client Status Changes

Clients must ensure that all royalty documents are completed using only valid client names and IDs. It is critical that royalty clients use current legal client names and their appropriate IDs on all documents to ensure accurate royalty calculation and to prevent provisional assessment and penalties. Rejects will occur when invalid IDs are used.

If you require information regarding client names or IDs, please contact Client Registry at 780-422-1395.

Nova Tolls - Multiple Gas Reference Prices

Royalty information related to the implementation of the Factor Model negotiated with industry for determining Multiple Gas Valuation Prices is provided on the Natural Gas website's Royalty Related Information page under Facility Royalty Trigger Factors and Meter Station Ties.

E. REMINDERS

Information on the Alberta Royalty Framework

Details on the changes to the Natural Gas Deep Drilling Program, New Royalty Formula and Gas Cost Allowance are available on the Alberta Energy Internet address: www.energy.alberta.ca. From "Our Business", navigate to "Natural Gas", "Legislation, Guidelines & Policies", "Gas Royalty Information Bulletins". These documents are also available under "About Us", navigate to "Royalty Framework".

Monthly Allowable Cost Estimates

With reference to the changes on Gas Cost Allowance, the following two new reports have been designed to show the calculated go-forward estimated costs for a production year. These reports are sent to royalty clients using the same mode of delivery as that of their invoice, and are available in CSV, PDF, and TXT formats.

1. **The Allowable Cost Estimates (ACEST) report**
   This report shows the calculated allowable cost estimates for capital, operating and custom processing at each Energy Resources Conservation Board (ERCB) facility, as well as the go-forward Facility Effective Royalty Rate (FERR).

The initial report that shows the 2009 calculated go-forward estimates were issued to royalty clients by the beginning of March 2009, before the January 2009 Billing Period (BP) invoice. Clients may submit a written request for an amendment to their go-forward estimated costs. The request is subject to department's review and approval.

Whenever there is a recalculation of the go-forward estimates in the system, the system will re-issue this report.

2. **The Monthly Allowable Cost Deduction (ACMTH) report**
   This report shows the details of the calculation of the estimated monthly Crown share of allowance for capital, operating and custom processing, to support the current month's Crown share of allowance on the invoice. It is sent monthly as part of the client's invoice package.

Amended Cost Estimates for the 2008 and 2009 Production Years

If a 2008 go-forward cost estimate was reviewed and manually changed before the December 2008 BP invoice, the system has replaced it with a new cost estimate calculated for 2009 in the January BP invoice. This new cost estimate does not take into consideration any information previously provided.

For new royalty clients with no cost history, if a go-forward cost estimate was manually processed for the 2008 production year, the system does not automatically set up a 2009 go-forward estimate. The clients must submit a written request together with supporting documentation for setting up their estimate.

If a go-forward cost estimate is manually processed in the January, February, March or April production months, the system will not replace it with a new go-forward estimate in the April Initial Annual Billing Period invoice. A client must submit a written request for a subsequent adjustment to be made.

Annual Allowable Cost (AC) Forms for 2009

The department will introduce new versions of the AC forms and will not accept the current versions for 2009 and subsequent production years' cost reporting.

If you require further information on these changes, please contact your respective Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin.

Otherwise Flared Solution Gas (OFSG) Royalty Waiver Program

The department reminds royalty clients that the OFSG program, for wells that have received ten years of OFSG royalty waiver, has been ended with production month January 2009. Should you have any questions, please contact Joyce Chen at 780-422-8083.

For the initial list of pre-qualified OFSG well events, you can go to the Information Bulletin – August 1999.

For the existing OFSG well events, you can go to Otherwise Flared Solution Gas Royalty Waiver Program (OFSG) Wells, for a MS Excel version or Adobe Acrobat version.

For applicable business rules and compliance information for the OFSG program, you can go to the Alberta Natural Gas Royalty Guidelines 2006 (Chapter 5, Section 2) and Natural Gas Royalty Regulation, 2009 (Schedule 7).

Historical Pricing and Royalty Data

A listing of historical royalty related data for information purposes was published in the February 2009 Information Bulletin.

Annual Weighted Average Gas Reference Price

The Annual Weighted Average Gas Reference Price for 2008 is $7.41. This price is used in the calculation to determine the 2008 minimum price for the Gas Corporate Average Price. Refer to Chapter IV, Section 1.9.6.3 of the Guidelines for additional information.

Weighted Average Aggregator Overhead Marketing and Administration Charges (OMAC)

For Gas Corporate Average Price (CAP) filers, when determining the netback value, the weighted average OMAC type charges may be deducted for sales to non-designated aggregators. Refer to Chapter IV, Section 1.9.6.1 of the Guidelines for additional information.

The Weighted Average Aggregator OMAC ($/GJ) for 2008 is $0.019. Refer to Chapter IV, Sections 1.5.7 of the Guidelines for additional information.

Monthly Sulphur Corporate Average Price Calculation – VA4 Form

The department requires royalty clients with an annual sulphur production of 30,000 tonnes or greater in the 2008 production year to file VA4 forms monthly, beginning with the January 2009 production month. The VA4 form is due on or before the 15th day of the second month following the respective production month. A royalty client whose annual sulphur production is less than 30,000 tonnes may choose to file the VA4 forms monthly beginning with January's production month; however, if this choice is made, the client must file VA4 forms for the entire year. The department will use the VA4 forms to determine each client's monthly Sulphur Corporate Average Price (S-CAP) and the monthly sulphur default price. We calculate each month's sulphur default price as the weighted average unit value of all arms length sales for all clients who filed VA4 forms for that month. The department will value and invoice the Crown royalty share of sulphur production monthly using the respective S-CAP price for clients who file VA4 forms, and the sulphur default price for clients who chose not to file VA4 forms. The VA4 form is subject to $100 in late filing penalties for each month or part of the month the form is past due. The VA4 form for the production month of January 2009 was due in the department by March 17, 2009.

Royalty clients who file monthly VA4 forms must file annual VA3 forms. The VA3 form remains the primary sulphur valuation tool and the S-CAP determined from each VA3 will replace the

entire year's monthly prices determined from the VA4 forms. The VA3 is due on or before April 15th of the year following the year of production. Interest is charged/paid on the Crown royalty difference when adjusting from monthly to annual valuation. The VA3 form is subject to a one-time $1,000 late filing penalty.

The following royalty clients must submit VA4 forms effective with the 2009 production year, which includes any pricing information for each of its consolidated/amalgamated entities:

Client ID	Client Name	Client ID	Client Name
0017	IMPERIAL OIL RESOURCES	0KT5	ESPRIT EXPLORATION LTD.
0039	TALISMAN ENERGY INC.	0PF8	HUNT OIL COMPANY OF CANADA, INC.
0054	SUNCOR ENERGY INC.	0R46	HUSKY OIL OPERATIONS LIMITED
0060	BP CANADA ENERGY COMPANY	0W9D	CONOCOPHILLIPS CANADA (BRC) PARTNERSHIP
0226	NEXEN INC.	0WW6	HIGHPINE ENERGY LTD.
0246	PETRO-CANADA	0YT7	MANCAL ENERGY INC.
0BP8	PENN WEST PETROLEUM LTD.	A05T	MEC OPERATING COMPANY ULC
0CW8	COMPTON PETROLEUM CORPORATION	A08J	ENERPLUS OIL & GAS LTD.
0D7E	ENCANA OIL & GAS PARTNERSHIP	A0L6	FAIRBORNE PIVOTAL PRODUCTION PARTNERSHIP
0F3F	DEVON CANADA	A162	DAYLIGHT ENERGY LTD.
0HE9	CANADIAN NATURAL RESOURCES LIMITED	A2F0	SHELL CANADA ENERGY
0JT1	EXXONMOBIL CANADA ENERGY	A2TG	TAQA NORTH LTD.

Turnaround Time for Allowable Cost (AC) Submissions

Facility Cost Centre Set-up/Change (AC1)
With the March 1 deadline of AC1 submissions for 2008, new FCC set-ups submitted through batch or on-line are processed by the department within a half-day turnaround time and these requests are not delayed due to an invoice cycle. All other FCC changes are processed overnight and do not occur during an invoice cycle. AC1s submitted on the weekend and on any statutory holiday are not processed until the next business day.

Annual Allowable Cost Submissions (AC2, AC3, AC4 and AC5)
AC2, AC3, AC4 and AC5 are processed nightly except:

- During an invoice cycle, and
- Submissions made on a weekend or on any statutory holiday, which will not be processed until the next business day.

F. POINTS OF CONTACT

Petroleum Registry of Alberta

The Petroleum Registry of Alberta Service Desk is the focal point for communications with the Registry regarding preparations for, access to, or utilization of the Registry. To contact the Petroleum Registry of Alberta Service Desk call: 1-800-992-1144.

Alberta Energy Internet

Prices, Royalty Rates, and Transportation Information are available on the Alberta Energy Internet address: www.energy.alberta.ca, from "Our Business", navigate to "Natural Gas", "About Natural Gas", "Prices", "Alberta Natural Gas Reference Price (ARP)".

In addition, both the Gas Royalty Calculation Information Bulletins and Information Letters are also available under "Our Business", navigate to "Natural Gas", "Legislation, Guidelines & Policies".

Gas Royalty Client Services

Gas Royalty Client Services is structured as a Business Associate client portfolio system, which assigns a given Business Associate to one of four Client Service teams. Listed below is the portfolio breakdown along with Client Service Team Leads and phone numbers. The portfolios are divided by company name and not by BA ID.

Example: If your company name is the "Gas Company" you would call C – G team at 780-644-1202.

Business Associate	Phone Number and Email Address	Team Lead
Numbered companies, A, B & L	780-644-1201 GRCST1@gov.ab.ca	Todd Atwood
C – G	780-644-1202 GRCST2@gov.ab.ca	Lily Hiew
H – P (excluding L)	780-644-1203 GRCST3@gov.ab.ca	Chris Nixon
Q - Z	780-644-1204 GRCST4@gov.ab.ca	Jyoti Bhambhani

Gas Royalty Reception: 780-422-8727
Fax: 780-427-3334 or 780-422-8732
Alberta Toll Free: 780-310-0000

Hours of operation are 8:15 a.m. to 4:30 p.m. Voice messages left after 4:30 p.m. will be answered the next business day.

In situations where a company has just amalgamated or purchased another company, the general rule is to call the team that is responsible for the "Supra" business associate, or Royalty payer.

Below are some guidelines for clients who are unsure which Client Services Team to call regarding their questions.

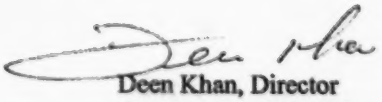
1. **Amalgamation/consolidation** - Call the team responsible for the "Supra" business associate (Royalty Payer).
   i.e. ABC Oil and Gas amalgamates with Zed Exploration and Zed is the amalgamator (royalty payer). When calling Client Services regarding business for ABC Oil and Gas, you would call Team 4 (Q-Z) (780-644-1204) because Zed Exploration is now the Supra business associate and royalty payer. This rule would apply even if you were calling regarding business that is prior to the acquisition or amalgamation.

2. **Asset Purchase** - Call the team responsible for your company.
   i.e. 123 Gas purchases the assets of TSP Exploration, but not the company. When calling Client Services regarding business for 123 Gas, you would call Team 1 (# Co., A, B, & L) (780-644-1201) because you have only purchased assets.

3. **Consultants/service providers** - If you have a contract to provide production accounting services to a company, call the team responsible for your client's company.
   i.e. Paul Snow Consulting Services enters into a contract with Duckback Oil and Gas and Olive Oil and Gas. Paul Snow would contact Team 2 (C-G) (780-644-1202) to discuss Duckback Oil business and Team 3 (H-P excluding L) (780-644-1203) to discuss Olive Oil and Gas business. At the time the contract is signed, Paul Snow would have had each company notify the appropriate team that he was authorized to access information for their company.

Reference Prices and Valuation Allowances Calculation Information

Gas Royalty Valuation and Markets
300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone: 403-297-5514
Fax: 403-297-5400



Deen Khan, Director
Gas Royalty Calculation
Royalty Operations – Edmonton

Attachments

2009 GAS AND ISC PRICES

MONTH	Gas Reference Price ($/GJ)	Methane ISC Reference Price ($/GJ)	Methane ISC Par Price ($/GJ)	Ethane ISC Reference Price ($/GJ)	Propane ISC Reference Price ($/GJ)	Butane ISC Reference Price ($/GJ)	Pentanes plus ISC Reference Price ($/GJ)
JAN	5.77	5.74	5.74	6.15	6.27	6.29	6.31
FEB	4.66	4.61	4.61	5.12	5.30	5.33	5.35
MAR							
APR							
MAY							
JUN							
JUL							
AUG							
SEPT							
OCT							
NOV							
DEC							

2008 Weighted Average Gas Reference Price ($/GJ)
7.412

2008 Weighted Average OMAC ($/GJ)
0.019

DETAIL OF THE FEBRUARY 2009 GAS AND ISC REFERENCE PRICES						
	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	5.019	4.989	5.361	5.494	5.488	5.489
Deductions: Intra – Alberta Transportation	0.301	0.320	0.182	0.129	0.099	0.075
Marketing Allowance	0.011	0.011	0.011	0.011	0.011	0.011
Price Before Pipeline Factor	4.707	4.658	5.168	5.354	5.377	5.403
Pipeline Fuel/Loss Factor	0.990	0.990	0.990	0.990	0.990	0.990
Price before Special Adjustment	4.662	4.613	5.118	5.304	5.326	5.352
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	4.662	4.613	5.118	5.304	5.326	5.352
Amendments: Carry forward (from previous RP month)	-0.001	0.000	-0.002	0.000	0.005	-0.002
Prior Period Amendment Adjustment (current RP month)	0.000	0.000	0.000	0.000	0.000	0.000
Calculated RP after Amendments	4.661	4.613	5.116	5.304	5.331	5.350
February 2009 Reference Price	**4.66**	**4.61**	**5.12**	**5.30**	**5.33**	**5.35**
Difference = value carried forward to next RP month	0.001	0.003	-0.004	0.004	0.001	0.000
Adjusted IATD (before Prior Period Amendments)	n/a	0.317	0.181	0.127	0.098	0.074
Prior period Amendments (IATD and Pipeline Fuel Loss)	n/a	0.000	0.000	0.000	0.000	0.000
Adjusted IATD (after Prior Period Amendments)	n/a	0.317	0.181	0.127	0.098	0.074

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NATURAL GAS LIQUIDS PRICES

MONTH	Ethane Reference Price ($/GJ)	Ethane Par Price ($/GJ)	Propane Reference Price ($/m3)	Propane Floor Price ($/m3)	Butane Reference Price ($/m3)	Butane Floor Price ($/m3)	Pentanes plus Reference Price ($/m3)	Pentanes plus Par Price ($/m3)	Sulphur Default Price ($ per tonne)
JAN	6.15	6.15	230.29	209.33	310.61	206.67	348.86	325.57	21.41
FEB	5.12	5.12	258.66	188.18	277.46	185.58	332.24	304.31	9.42
MAR									
APR									
MAY									
JUN									
JUL									
AUG									
SEPT									
OCT									
NOV									
DEC									

ANNUAL SULPHUR DEFAULT PRICE

2003	2004	2005	2006	2007
31.24	31.88	33.98	18.82	32.82

2009

NGL TRANSPORTATION ALLOWANCE AND DEDUCTIONS

MONTH	PENTANES PLUS (a)				PROPANE AND BUTANE (b)				PENTANES PLUS, PROPANE & BUTANE (c)				FRAC. ALLOW. (per m3)
	REGION				REGION				REGION				
	1	2	3	4	1	2	3	4	1	2	3	4	
JAN	27.97	10.55	36.88	18.00	39.25	25.79	33.99	-3.31	40.23	45.50	43.56	29.53	17.25
FEB	25.80	30.88	42.93	25.11	27.25	12.51	21.86	-11.81	46.71	47.25	67.48	33.91	17.25
MAR													
APR													
MAY													
JUN													
JUL													
AUG													
SEPT													
OCT													
NOV													
DEC													

(a) Pentanes Plus obtained as a specification gas product,
(b) Propane and Butane obtained as specification products, and
(c) Pentanes Plus, Propane and Butane contained in a natural gas liquids mix.

Note: For details on "Prior Period Amendment Effects", see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS												
NGL REFERENCE PRICES	February 2009											
	Propane		*Butanes*		*Pentanes*							
Price before amendments	258.668203		286.837610		332.241008							
Opening Rollover (from prior business mth)	-0.003762		-0.003417		0.001025							
Prior Period Amendment Adj. (NGL-100)	0.000000		-9.370728		0.000000							
Published Reference Price	**258.66**		**277.46**		**332.24**							
TRANSPORTATION ALLOWANCES	February 2009											
	Pentanes Plus				Propane and Butane				Pentanes Plus, Propane & Butane			
AMENDMENTS	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4
Opening Rollover (from prior business mth)	0.002425	0.002443	-0.003166	0.004290	0.001175	0.004524	0.003554	0.001179	-0.003571	-0.003970	0.000348	0.004102
Prior Period Amendment Adj. (NGL-100)	0.000000	0.000000	0.000000	0.000000	-4.811869	-3.035345	-4.162491	0.000000	-1.903716	-2.674195	-1.661360	-2.253123
Total Amendment Effect	0.002425	0.002443	-0.003166	0.004290	-4.810694	-3.030821	-4.158937	0.001179	-1.907287	-2.678165	-1.661012	-2.249021
Calculated Transp. Differential	25.801668	30.875350	42.933146	25.101262	32.057887	15.535844	26.023901	-11.812955	48.620775	49.924251	69.140548	36.161393
Calculated Transp. Differential after Total Amendments	25.804093	30.877793	42.929980	25.105552	27.247193	12.505023	21.864964	-11.811776	46.713488	47.246086	67.479536	33.912372
Published Transportation Allowance	**25.80**	**30.88**	**42.93**	**25.11**	**27.25**	**12.51**	**21.86**	**-11.81**	**46.71**	**47.25**	**67.48**	**33.91**

Effective the January 2009 production period, the royalty rates for **methane** and **ethane** will be calculated based on a new royalty formula. The new royalty formula consists of the sum of a price component and a quantity component. The new royalty rates will range from 5% to 50%. **Propane** and **butanes** will have fixed royalty rates of 30%, whereas **pentanes plus** will have a fixed royalty rate of 40%.

The price component of the new royalty formula royalty rate for methane and ethane is determined by the monthly methane or ethane par price (PP)

Price ($/GJ)	r_p
PP ≤ 7.00	(PP – 4.50) * 0.0450
7.00 < PP ≤ 11.00	(PP – 7.00) * 0.0300 + 0.1125
PP > 11.00	(PP – 11.00) * 0.0100 + 0.2325
Maximum	30%
Minimum	Can be negative (-20.25% if PP=0)

The par price is a provincial weighted price determined by the department and published in the Information Letter for each production month. Determination of the par price has not changed under the Alberta Royalty Framework.

The quantity component of the new royalty formula royalty rate for methane and ethane is based on the average daily production (ADP) of the well event. The quantity component is adjusted for either the depth of the well event and/or the acid gas content of the well event.

Quantity ($10^3m^3/d$)	r_q
ADP≤ (6 * DF)	[ADP – (4 * DF)] * (0.0500/DF)
(6 * DF) < ADP ≤ (11* DF)	[ADP – (6 * DF)] * (0.0300/DF) + 0.1000
ADP > (11* DF)	[ADP – (11 * DF)] * (0.0100/DF) + 0.2500
Maximum	30%
Minimum	Can be negative

The ADP for a well event is the total raw gas production in thousand cubic metres (10^3m^3) for the month divided by the total hours of production in that month multiplied by 24. The ADP formula is as follows:

$$\text{ADP} = \frac{\text{total raw gas production}}{\text{total hours of production}} \times 24$$

Acid Gas Factor (AGF) is a factor that adjusts the ADP of a well event if that well event is producing high amounts of acid gas, that is, if the combined concentration of hydrogen sulphide (H2S) and carbon dioxide (CO_2) is greater than 3% and less than or equal to 25%. If a well event has an acid gas content of less than or equal to 3%, then the AGF of the well event will default to 1.00. If a well event has acid gas content greater than 25% then the AGF has a minimum value of 0.78.

The AGF is determined based on the following formula:

$AGF = [1.03 – (H_2S\% + CO_2\%)]$

The ADP is adjusted by multiplying the ADP by the AGF, that is:

Adjusted ADP = ADP * AGF

The acid gas content of a well event, used by the department for the determination of the AGF, will be according to the records of the ERCB.

A depth factor (DF) is required for all well events, and is calculated based on the measured depth (MD) according to the records of the ERCB for that well event. Information on the MD, of a well event, can be found on the Petroleum Registry of Alberta (PRA) in the 'Infrastructure' section.

The DF is used in the determination of the quantity component (r_q) of the royalty rate; it adjusts the quantity component royalty formula for measured depths that exceed 2000 metres. The DF for a well event is determined based on the following formula:

$$DF = \left(\frac{MD}{2000}\right)^2$$

A well event with a MD greater than 2,000 metres will receive a royalty adjustment based on production from the well event. A well event without a reported MD or with MD less than or equal to 2,000 metres will have a DF of 1.00. The DF is capped at 4.00 for well events with MD greater than or equal to 4,000 metres.

If the MD is

- ≤ 2,000 metres, then the DF=1.00
- >2,000 metres and <4,000 metres, then DF= $\left(\frac{MD}{2000}\right)^2$
- ≥4,000 metres, then the DF=4.00